Waterflooding in Gordon Sandstone Formation – Wileyville Field

during the Period 05/15/2001 to 09/30/2002

By

José Zaghloul, Mario Farías, Turgay Ertekin, and Robert Watson (PNGE – PSU)
Terry Pegula, and William Fustos (East Resources Inc.)

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The College of Earth and Mineral Science
The Department of Energy and Geo-Enviromental Engineering
The Energy Institute
East Resources Incorporated

April 20, 2003

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By
The Pennsylvania State University
The College of Earth and Mineral Science
The Department of Energy and Geo-Enviromental Engineering
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ABSTRACT

The Appalachian Region contains hundreds of oil fields that were developed during the late 1800's and/or early 1900's. These fields contain oil reserves that may be recovered using secondary recovery methods such as waterflooding. Technical and economic evaluation of these fields for these capital-intensive operations requires in-depth engineering studies that usually include a field-scale computer model. However, the data needed for building such models are lacking given that modern tools for formation evaluation were not available when these fields were developed (early 1900's).

The objective for this study was to analyze the Wileyville field located in the Wetzel County, West Virginia, for the purpose of improving the performance of an ongoing water flood. To accomplish this objective it was necessary to develop a simulation methodology for a reservoir containing sparse data sets.

This study describes the approach, and protocol employed to characterize and build the computer model of the field in spite of the sparse data sets. The protocol utilizes a systematic approach to complete the history matching, which proved to be effective in understanding the behavior of the reservoir under study. The results obtained provide the operators of the Appalachian basin with a tool to characterize, initialize and perform computer simulation studies of any of the hundreds of reservoirs found in the basin.

From the results obtained, it was concluded that the change in well-bore damage with time in waterflooding operations might result from the types of fluids injected. In the Wileyville field study, it was concluded that the heterogeneous nature of the formation was the principal factor that impacted productivity and injectivity. Moreover, it appears that there is a correlation between production and injection well damage and the physical location of wells within the field.

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1.0 INTRODUCTION

The goal of reservoir engineering and its attendant studies is to maximize oil recovery from the subject reservoir. During the primary production phase, it is the management of the natural energy of the reservoir that maximizes the production. However, continued production at an economic level typically requires implementation of secondary recovery technologies such as waterflooding. These projects tend to be capital-intensive and as such, demand use of modern reservoir techniques such as numerical simulation for their design and optimization.

These simulation studies demand a significant amount of reservoir specific data. This data include production and pressure history and wireline logs. In the case of fields such as the Wileyville Field in West Virginia, the field was developed for primary production before many of the commonly used technologies were developed. These technologies include wireline logs and downhole pressure measuring devices. Moreover, much of the individual well production data in terms of daily and total production, were not available. To accomplish the stated objective of this study which was to evaluate the ongoing waterflooding operations at the Wileyville field, it was necessary to develop a protocol for use when dealing with the simulation of reservoirs with sparse or incomplete data sets.

It is postulated that this protocol will be of a value to other operators in the Appalachian basin who may consider the implementation of enhanced recovery in these first generation oil fields that were developed for primary production during the late eighteenth and early twentieth centuries. Moreover, the model itself will be of a specific value to the operator of the Wileyville field who may consider additional development in this field or to optimize its operations.

1.1 Background

To accomplish this study, data from ongoing field operations were used. The data were from the Gordon sandstone formation found in the Appalachian Basin. The Gordon sand belongs to the Venango group of the Upper Devonian age and received its name in 1885 when discovered by drilling operations on the Gordon farm in Washington, Pennsylvania.

Among the most predominant properties that characterize the sandstone at this location are: 1) the depth at which it is found (between 1500-ft and 3000-ft); 2) the permeability ranges (from 90-md to 200-md); and 3) the average porosity value of approximately 20 percent. Values out of these ranges could generally be found in any of the wells penetrating this formation (Harper, 1987 and Lytle, 1950).

The area of interest for the study is located in Wetzel County, northwest West Virginia, where the fields of Wileyville is located. This field produces from the Gordon sand formation and is one of the many fields found in Pennsylvania, Ohio and West Virginia that have the potential for waterflooding.

As previously stated, fields penetrating the Gordon formation were discovered in the late 1800s and at the beginning of the 20th century. During the early development stage of the fields, primary production was the principal mechanism for oil production. However, this primary production ended by the middle of the century because the reservoir drive mechanism was depleted. It was estimated that approximately 10 to 25 percent of the original oil in place had been recovered. Therefore, alternative recovery methods have been studied to keep these stripper well reservoirs economically profitable (Cardwell, 1978). Stimulation and secondary oil recovery projects were applied to different areas of the reservoir, with varying degrees of success. Gas injection and waterflooding were the most widely secondary recovery methods even though air injection has also been practiced.

It is suggested in this study that waterflooding of the Wileyville is feasible from a technical perspective. Moreover, the study suggests that a computer model of a field with sparse data sets can be developed. The prerequisite is a close partnership between the modeling team and the field operators where an active an ongoing exchange of data takes place. Performance of the field can then be compared between that experienced in the field and that predicted by the computer. Variances can then be used to adjust the model and improve its performance.

1.2 PROBLEM STATEMENT

The skin factor is the representation of a damaged or stimulated wellbore. Skin damage is present from the time a well is drilled, and then completed. It is present during the entire life of the well whether the well is in operation for production or injection purposes.

Although skin effect has been the subject of numerous investigations, e.g. Fetkovich (1973), Tippie et al. (1974), Blacker (1982) and Hansen et al. (2002), the dynamic nature of the phenomenon has not been thoroughly investigated. Dynamic skin is influenced by a variety of parameters that cause the productivity index of the well to vary. It is well understood that operating conditions are not always the same. For example, the reservoir conditions may change with oil production and fluid injection rates may vary with well stimulation and/or mobilization of suspended particles by the injected fluid. These changes and their impact on the wellbore (skin damage) must be considered in conducting a reservoir analysis.

Analysis of the impact of dynamic skin on production and injection rates is the focus of this investigation. To achieve this objective, the behavior of the Wileyville field is analyzed. This field is currently undergoing waterflooding,. The results of this analysis are used to provide insight concerning the dynamic skin.

The representation of the dynamic skin effect is made with numerical reservoir simulation. A commercial black oil model simulator (Eclipse 100) is used as the tool to pursue the principal objective of this study. The methodology used to develop the model is the history matching process, which when coupled with current field operating reports confirm the veracity of this approach.

2.0.CHARACTERIZATION OF THE GORDON SANDSTONE

Reservoir characterization includes estimating and formatting of the reservoir data needed to build a model in a form that can be used by the simulator. Reservoir characterization includes the selection of a grid and associated data for use in the model. Data acquisition is an essential part of the model characterization and initialization, and the quantity and quality of the data used to initialize the model play a relevant role in the effectiveness and reliability of the history matching.

Parish et al. (1993) mentioned that two important tasks of the engineer conducting a history matching are: make a careful assessment of the observed data to be matched and making an assessment of the basic reservoir description. The description of a reservoir involves the estimation of its rock and fluid properties. There are many techniques to estimate the value of different properties, such as permeability or porosity, in different locations of a reservoir. Many of these techniques interpolate values from the analysis of the data obtained from a few wells drilled in certain strategic locations of the field.

In this study, four steps were followed to develop an initial description of the reservoir:

1. A description of the area extent and reservoir structure is developed. To this description, a grid is applied.
2. A model of the fluids is developed. Where specific data describing the intrinsic properties are not available, suitable correlations available from the literature are used.
3. Rock properties such as porosity, initial phase saturations, relative permeability, absolute permeability and capillary pressure are estimated at locations throughout the reservoir.
4. Data based on the historical development of the field are then used to initialize the field model.

In this study, most of the properties of the fluids involved are not known; therefore, there was the need to estimate the fluid properties by means of assumptions and correlations. Also, some of the rock properties of the field are not known, such as absolute permeability, relative permeability, and fluid saturations. In this case, different approaches are proposed to estimate the data needed to initialize and characterize the Wileyville reservoir. This is done in order to complete the representation of the model and guarantee the consistency of all the assumptions made.

Initialization of the reservoir properties depends upon an appropriate description of the field's history to allow an efficient history matching process and the best possible representation of the actual behavior of the reservoir. The question that must be addressed by the modeler is the "uniqueness" question and the reasonableness of any predictions made using the model. As previously indicated, data sets from a field currently under development (Wileyville field) were used to sustain the proposed approach.

2.1 Characterization of the Wileyville field

2.1.1 Field Structure and grid description

The Wileyville field, a shallow inland oilfield located in Wetzel County, West Virginia is approximately 100 miles SSW of Pittsburgh, Pennsylvania. This field produces from the Upper Devonian Gordon Sandstone. This sandstone is blanket sand and can be described as a spoon-shaped syncline.

The operator of the field, East Resources Co, provided a structure map and a net pay thickness isopach map. These maps were used to identify the external boundaries of the field and the thickness of each region of the reservoir. These maps were developed using wireline log readings obtained from different wells in the field. The Gordon sandstone at Wileyville is located at an approximate depth of 3000-ft. It has an average net pay thickness of 12 feet. The reservoir has an estimated area of 2435 acres. These maps provided the basis for constructing the grid of the model.

The model development involved the creation of a non uniform, two-dimensional grid. The decision to develop a two-dimensional grid was based on the assumption that the properties of the sand are uniform throughout the thickness of the sand. This assumption is supported by the results of an analysis performed by Core laboratories Inc, on a core extracted from the L. S. Hoyt 100 well of the Wileyville field.

The model contains 498 active blocks, 23 production wells and 18 water injection wells. Figure 2-1 illustrates the location of the wells, and Table 2-1 lists the wells, and their location in the grid system. Tables 2-2 and 2-3 list the width and the height of each block respectively, according to its coordinates in the numerical grid..

The Wileyville field is a closed reservoir, therefore the external boundary conditions of the model are no flow boundaries. The internal boundary conditions are defined as follows: the production wells are modeled by assuming a constant bottom hole pressure of 95 psig, and the water injection wells maintain a constant bottom hole pressure equivalent to the wellhead pressure plus the pressure exerted by the hydrostatic column of water in the well.

2.1.2 Fluid properties

Due to the lack of information about the reservoir fluid properties, several correlations and assumptions were used to develop a thermodynamic and physical black-oil model capable of simulating the behavior of the reservoir fluids under the various operating conditions. Little information is available to estimate the physical properties of the reservoir fluids. The properties known include an oil API gravity of 40° (Lytle, 1950), and bubble point pressure of 780 psia (Pennzoil, 1985).

The characteristics of the gas present in the Wileyville field are known. The specific gravity of this gas was determined to be 0.9 using a gas chromatographic analysis. Gas Analysis Systems, Inc. performed this analysis, during June 2001. The water specific gravity was assumed constant and equal to 1.0, and the gas phase was assumed immiscible in the water phase. Also, it was assumed that the temperature of the reservoir remains constant at all times.

Given the sparse information known about the properties of the fluids present in this field, a PVT model was developed using published correlations. The PVT model developed is a black-oil model, with the capability to simulate dissolved gas in the oil phase.

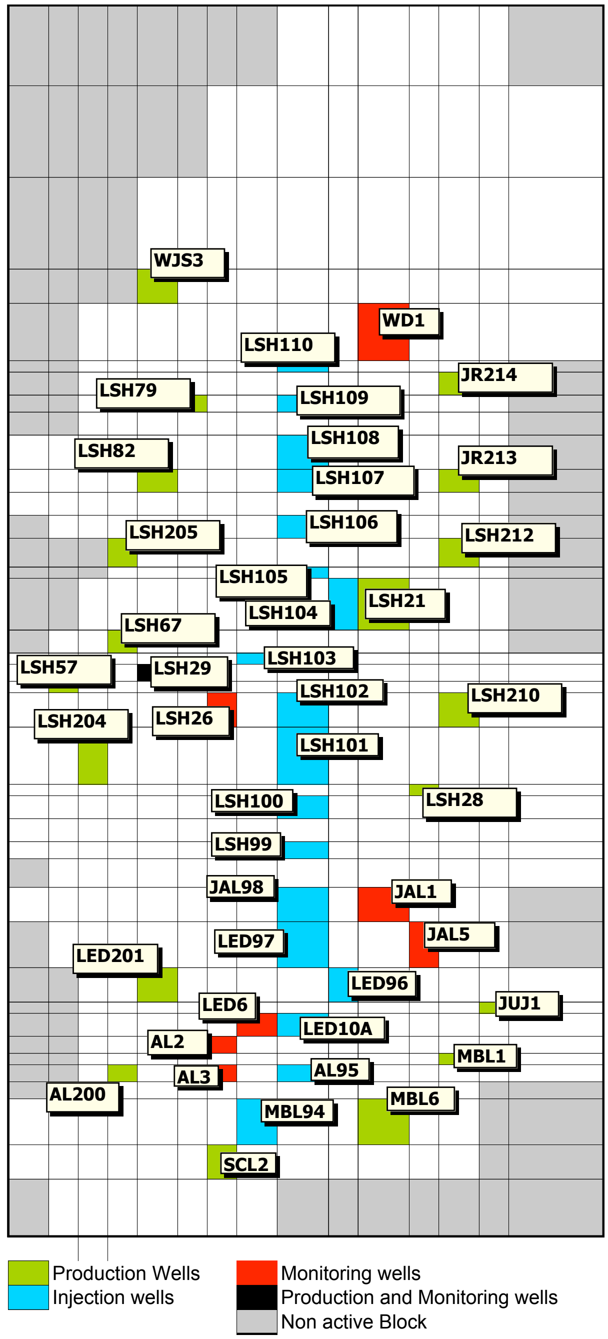

Figure 2-1. Location of the wells in the grid of the Wileyville field

Farm	ID	Code	#	Locat.	
				X	Y
INJECTION WELLS					
L.S. Hoyt	1711	LSH	110	9	6
L.S. Hoyt	1717	LSH	109	9	8
L.S. Hoyt	1716	LSH	108	9	10
L.S. Hoyt	1710	LSH	107	9	11
L.S. Hoyt	1709	LSH	106	9	13
L.S. Hoyt	1708	LSH	105	9	15
L.S. Hoyt	1721	LSH	104	10	16
L.S. Hoyt	1707	LSH	103	8	18
L.S. Hoyt	1706	LSH	102	9	21
L.S. Hoyt	1705	LSH	101	9	22
L.S. Hoyt	1685	LSH	100	9	24
L.S. Hoyt	1704	LSH	99	9	26
Jacob A. Lantz	1720	JAL	98	9	28
Louise E. Dulaney	1719	LED	97	9	29
Louise E. Dulaney	1718	LED	96	10	30
Louise E. Dulaney	1749	LED	10A	9	32
Ara Long	1743	AL	95	9	35
Mary B. Long	1742	MBL	94	8	37
PRODUCTION WELLS					
W.J. Santee	1457	WJS	3	5	4
L.S. Hoyt	1532	LSH	79	6	8
L.S. Hoyt	1003	LSH	82	5	11
L.S. Hoyt	1773	LSH	205	4	14
L.S. Hoyt	O994	LSH	67	4	17
L.S. Hoyt	1218	LSH	29	5	19
L.S. Hoyt	O992	LSH	57	2	20
L.S. Hoyt	1744	LSH	204	3	22
Jennetta Chamberlain	1745	JC	203	4	25
Louise E. Dulaney	1748	LED	202	4	28
Louise E. Dulaney	1797	LED	201	5	30
Ara Long	1777	AL	200	4	35
Sarah C. Long	1027	SCL	2	7	38
Mary B. Long	1026	MBL	6	11	37
Mary B. Long	1022	MBL	1	13	34
J. U. Jaliff	1007	JUJ	1	14	31
L.S. Hoyt	1217	LSH	28	12	23
L.S. Hoyt	1776	LSH	210	13	21
L.S. Hoyt	SN	LSH	21	11	16
L.S. Hoyt	1774	LSH	212	13	14
Jonh Rush	1775	JR	213	13	11
Jonh Rush	1772	JR	214	13	7
MONITORING WELLS					
Ara Long	1020	AL	3	7	35
Ara Long	1019	AL	2	7	33
Louise E. Dulaney	963	LED	6	8	32
Jacob A. Lantz	1013	JAL	5	12	29
Jacob A. Lantz	1010	JAL	1	11	28
L.S. Hoyt	1216	LSH	26	7	21
L.S. Hoyt	1218	LSH	29	5	19
Weslye Dulaney	S/N	WD	1	11	5

Table 2-1. Names and location of the wells (Wileyville field)

X Coord.	DX [ft]
1	375
2	250
3	250
4	250
5	375
6	250
7	250
8	375
9	500
10	250
11	500
12	250
13	375
14	250
15	1000

Table 2-2. Width of each block of the grid system (DX – Wileyville field)

Y Coord.	DY [ft]
1	1750
2	2000
3	2000
4	750
5	1250
6	250
7	500
8	375
9	500
10	750
11	500
12	500
13	500
14	625
15	250
16	1125
17	500
18	250
19	375
20	250
21	750
22	1250
23	250
24	500
25	500
26	375
27	625
28	750
29	1000
30	750
31	250
32	500
33	375
34	250
35	375
36	375
37	1000
38	750
39	1250

Table 2-3. Height of each block of the grid system (DY – Wileyville field)

The PVT model requires the determination of certain properties at different pressure conditions. For the oil phase, these properties were: solution gas-oil ratio (R_s), oil formation volume factor (B_o), oil compressibility (c_o), and oil viscosity (μ_o).

The solution gas-oil ratio at different pressures was estimated using a correlation developed by Glaso in 1980. This correlation is shown below:

$$R_s = \gamma_g \left[\frac{API^{0.989}}{T^{0.172}} 10^{Y} \right]^{1.22549}$$

where:

R_s = solution gas-oil ratio, SCF/STBO

T = temperature,°F

API = oil API gravity

γ_g = specific gravity of the gas at standard conditions

and Y is defined as follows:

$$Y = \frac{1.7447 - \sqrt{5.1797 - 1.2087 * \log(p)}}{0.6044}$$

where:

p = pressure, psia.

The oil formation volume factor was determined using the following correlation developed by Standing:

$$B_o = 0.972 + 0.000147 F^{1.175}$$

where:

B_o = oil formation volume factor, bbl/STBO

The F factor is determined using the following equation:

$$F = R_s \sqrt{\frac{\gamma_g}{\gamma_o}} + 1.25T$$

where:

R_s = solution gas-oil ratio, SCF/STBO

T = temperature,°F

γ_g = specific gravity of the gas at standard conditions

γ_o = specific gravity of the oil at standard conditions

The oil compressibility was determined by means of the Vazquez and Beggs correlation shown below:

$$c_o = \frac{-1433 + 5R_s + 17.2T - 1180\gamma_{gc} + 12.61API}{10^5 p}$$

where:

c_o = oil compressibility, psi-1

R_s = solution gas-oil ratio, SCF/STBO

T = temperature,°F

API = oil API gravity

γ_g = specific gravity of the gas at standard conditions

γ_o = specific gravity of the oil at standard conditions

p = pressure, psia

Finally, the oil viscosity was estimated using the Beggs & Robinson correlation:

The viscosity of the live oil is determined by:

$$\mu_{ol} = \left(10.715\left(R_s + 100\right)^{-0.515}\right)\mu_{od}^{\ b}$$

where:

μ_{ol} = viscosity of the live oil, cp

μ_{od} = viscosity of the dead oil, cp

R_s = solution gas-oil ratio, SCF/STBO

The b factor is calculated by the following equation:

$$b = 5.44(R_s + 150)^{-0.338}$$

The viscosity of the dead oil is estimated using the correlation shown below:

$$\mu_{od} = 10^x - 1$$

where x is calculated as:

$$x = \frac{10^{(3.0324 - 0.02023API)}}{T^{1.163}}$$

For the water phase the only properties estimated at different pressures were the water formation volume factor (B_w), the water compressibility (C_w), and the water viscosity (μ_w). The water formation volume factor was estimated by means of the Gould correlation:

$$B_w = 1.0 + 1.2x10^{-4}(T - 60) + 1.0x10^{-6}(T - 60)^2 - 3.33x10^{-6}p$$

where:

B_w = Water formation volume factor, bbl/STBW

T = temperature,°F

p = pressure, psia

The water compressibility was calculated using the Meehan correlation for gas free water.

$$c_w = 10^{-6}\lfloor A + BT + CT^2 \rfloor$$

where:

c_w = water compressibility, psi-1

T = temperature,°F

and the variables A, B, and C are defined as:

$$A = 3.8546 - 0.000134p$$
$$B = -0.01052 + 4.77x10^{-7}\,p$$
$$C = 3.9267x10^{-5} - 8.8x10^{-10}\,p$$

where:

p = pressure, psia

The water viscosity is estimated by means of the Beggs & Brill correlation, shown below:

$$\mu_w = \exp\left(1.003 - 1.479x10^{-2}\,T + 1.982x10^{-5}\,T^2\right)$$

where:

μ_w = water viscosity, cp

T = temperature,°F

For the gas phase, there was the need to determine the gas compressibility (B_g), and the gas viscosity (μ_g) at various pressures. The formation volume factor was determined using the real gas equation of state, where:

$$B_g = 0.0283\frac{ZT}{p}$$

where:

B_g = gas formation volume factor, Cf/SCF

T = temperature,°R

p = pressure, psia

z = gas compressibility factor

To calculate the viscosity of the gases the Lee et al correlation (1966) was employed. This correlation is shown below:

$$\mu_g = K \times 10^{-4} \exp\left[X \left(0.0433 \gamma_g \frac{p}{Z(T+460)} \right)^{Y} \right]$$

where:

μ_g = gas viscosity, cp

T = temperature,°R

p = pressure, psia

z = gas compressibility factor

The variables K, X and Y are defined as follows:

$$K = \frac{(9.4 + 0.02M_a)(T+460)^{1.5}}{209 + 19M_a + (T+460)}$$

$$X = 3.5 + \frac{986}{(T+460)} + 0.01M_a$$

$$y = 2.4 - 0.2X$$

where:

M_d = Molecular weight of the gas.

Even though the fluid properties available to build the model were sparse, the correlations and assumptions employed allowed building a complete PVT model that is able to simulate the behavior of the three phases involved in the reservoir.

2.1.3 Rock properties

The formation studied is the Upper Devonian Gordon Sandstone. The rock properties of interest to perform this simulation study are: porosity, absolute permeability, relative permeability, initial saturations, and capillary pressure.

The porosity in different locations of the field was determined using pore-feet maps provided by the operator of the field. This pore-feet map allowed calculating the porosity in all the grid blocks of the numerical model.

There was no information available for the saturations distribution in the field. However, the operator indicated that it was reasonable to initialize the model assuming that the water saturation throughout the entire reservoir is 25% and the gas saturation is 25%. This estimate of saturations provided by the operator is based on their experience operating wells throughout the basin.

There was one core available for use in the Wileyville study: The analysis was performed by Core Laboratories, Inc. on a core obtained from the L. S. Hoyt 100 well. The results of the analysis included relative permeability curves that were used in creating characteristic relative permeability curves for the simulation (Figure 2-2). Additionally, this core was also used to provide information for estimating the value of absolute permeability. The value of average absolute permeability of this core is 50-md.

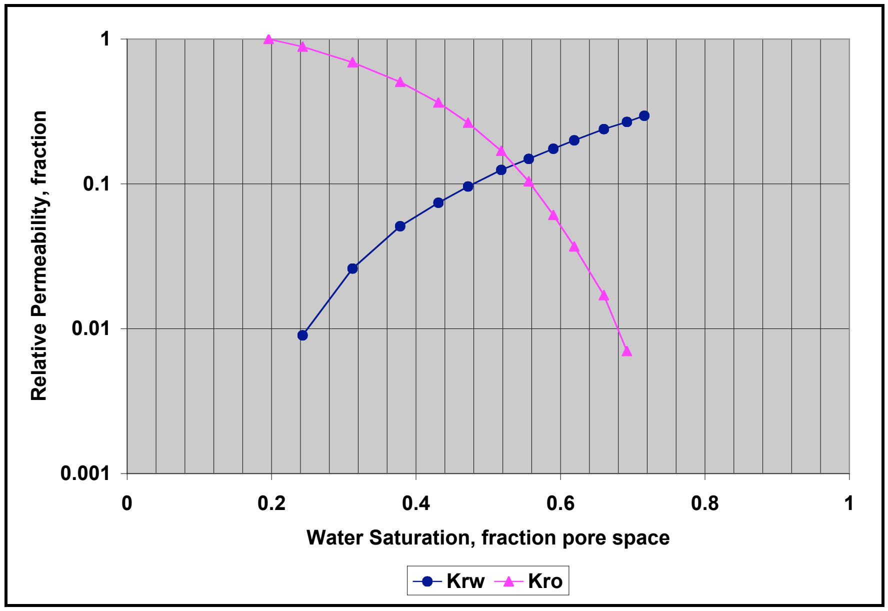

Figure 2-2. Kr vs. Sw. (L. S. Hoyt 100 Well, Wileyville Field)

2.1.4 Historical development of the waterflooding

Water injection at Wileyville began in February 1997. At this time there were 41 active wells. Of these wells, 18 are injection wells that are arranged in a line drive pattern. The remaining 23 production wells are located east and west of the injection wells toward the external boundaries of the reservoir. Since water injection started, there has been injected 5,300,000 barrels of water, and the field started to show a significant response in terms of formation water and/or oil production in May of 2002.

3.0 RESULTS & DISCUSSION

3.1 History matching results

After a several iterations during which the parameters in the simulation model were adjusted, a satisfactory history match was achieved. The results obtained indicated an acceptable model behavior, which mimics the operation of the field since waterflooding was initiated in February 1997. The following sections contain a discussion of the results of the history matching.

3.1.1 Discussion of the results of the Injection match

The results of the injection match were compared using a two-step process. In the first step, the trends of the actual and the simulated curves were compared qualitatively to ensure that the trends of both curves are similar. Second, the values of the actual and the simulated cumulative water volumes injected were computed and compared, and indicated a small difference in the values injected (less than 15%).

The results show that the simulated water injection behavior is qualitatively close to the actual injection trend. Consequently, it can be seen that the simulated cumulative water injection of the field scale match is in good agreement with the actual water injected in the reservoir (Figure 3-1).

The cumulative water injected for the actual operation and for the simulation was computed and compared to verify that the actual and simulated water injected volumes were similar. In this case, the acceptance criteria established that the error should not be higher than 10 %. This value is based on the accuracy of the orifice meters used to measure the water injection rates for each well.

Figure 3-2 compares the actual and the simulated cumulative water volumes injected for each well, while Figure 3-3 shows the error or relative deviation in the cumulative water injected for each well. This figure shows that 15 out of 18 wells are within an error margin of 10%. This error is considered to be acceptable for this study, given the accuracy of the instruments used to measure the injection water rates for each well.

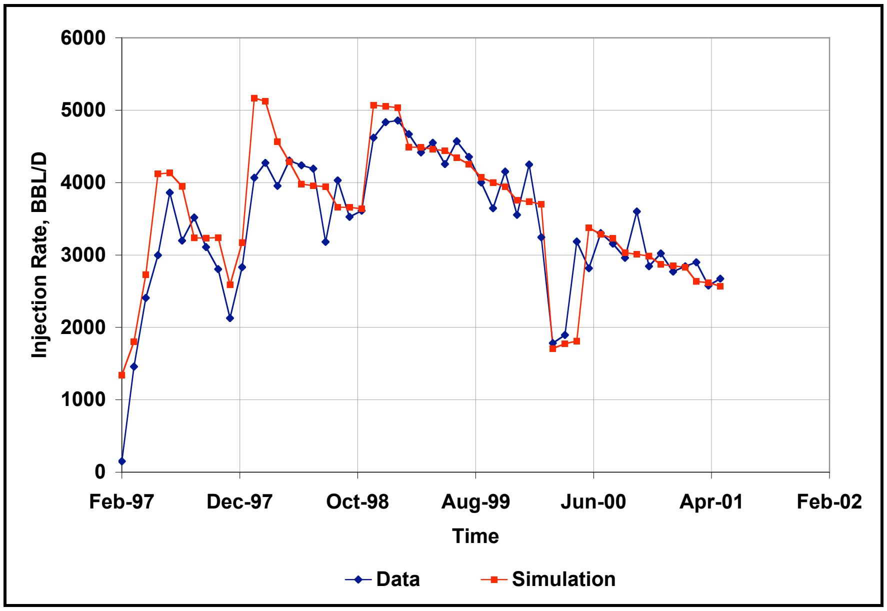

Figure 3-1. Field water injection rate vs. time. Field data vs. simulation results

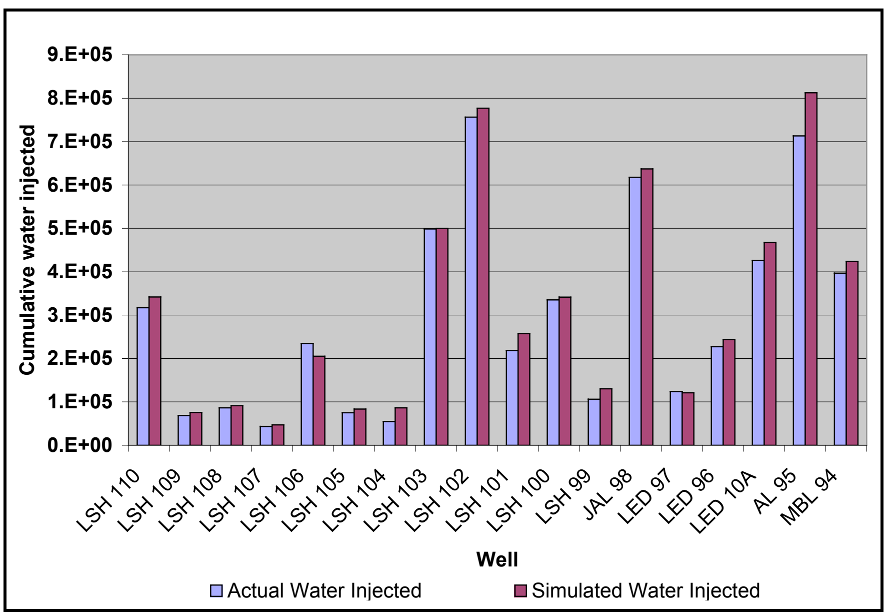

Figure 3-2. Cumulative water injected. Field data vs. simulation results

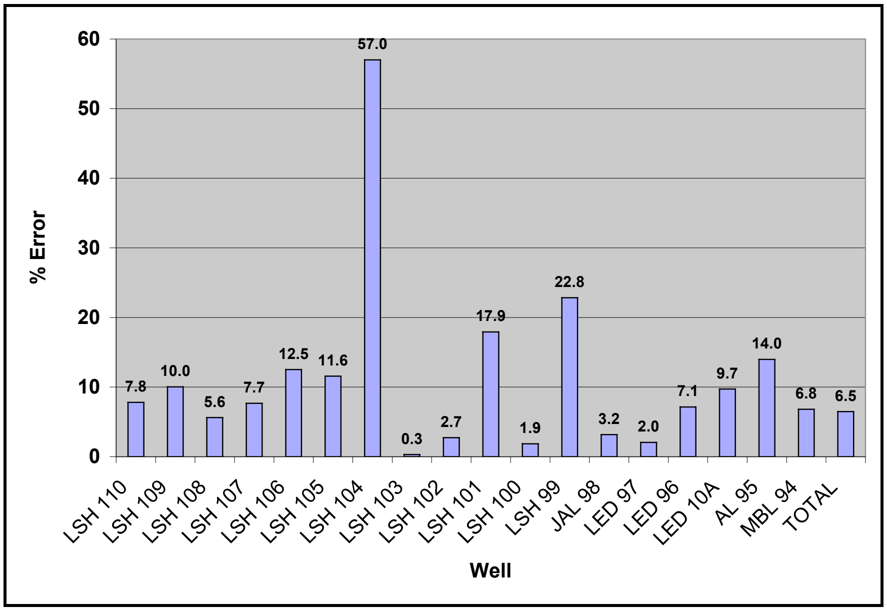

Figure 3-3. Error in cumulative water injection

Only three wells show an error greater than 10%. These wells are L.S. Hoyt 104 (LSH 104), L.S. Hoyt 99 (LSH 99), and L.S. Hoyt 101. Even though the error is greater than the established "acceptable" value for this study, the difference between the actual and the simulated water volume injected for each well is small compared to the water volume injected in the field (about 4%). Consequently, this error is not considered to be significant and its impact on field behavior is minimum.

Finally, it is important to note that the trend of the water injection curves matches qualitatively the behavior for all the injection wells. The deviation in the water volume computed for each well is "acceptable" for the above-explained reasons, and the error in the total water injection of the field is within 7%. Based on these observations, it can be concluded that the water injection match is acceptable.

3.1.2 Discussion of the results of the pressure match

Table 3-1 shows that all the pressures calculated by the model match the pressures obtained from the field, within an error margin of 16%. This error is acceptable given the resolution of the instruments used to read the fluid levels in the wells.

The only well where the error between the actual pressure obtained from the field, and the pressure calculated by the simulator is greater than 20% is the well J.A. Lantz 1 (JAL 1). Even though the error is greater than 20%, the difference between the pressures obtained from the field and the pressure calculated by the simulator for (JAL 1) well is not significant (41 psi). Given the resolution of the instruments used to measure the fluid levels in the wells, it can be concluded that the results of the pressure match are acceptable.

WELL	LOCATION	REAL	SIMULATED	DIFF	ERROR
WD1	(11,5)	476	399	77	16%
LSH29	(5,19)	778	795	-17	2%
LSH26	(7,21)	766	848	-82	11%
JAL1	(11,28)	150	191	-41	28%
JAL5	(12,29)	138	119	19	14%
LED6	(8,32)	693	726	-33	5%
AL2	(7,33)	232	270	-38	16%
AL3	(7,35)	1028	1114	-86	8%

Table 3-1. Pressures measured in the field vs. pressures calculated by simulation

3.1.3 Discussion of the results of the production match

Figure 3-4 compares the actual and simulated production of oil and water for the field. The results show a good qualitative match, since the trends of the actual and the simulated curves for each phase are in good agreement.

Figure 3-5 compares the actual and simulated oil production for each well in the field, while the water data shown in Figure 3-6.

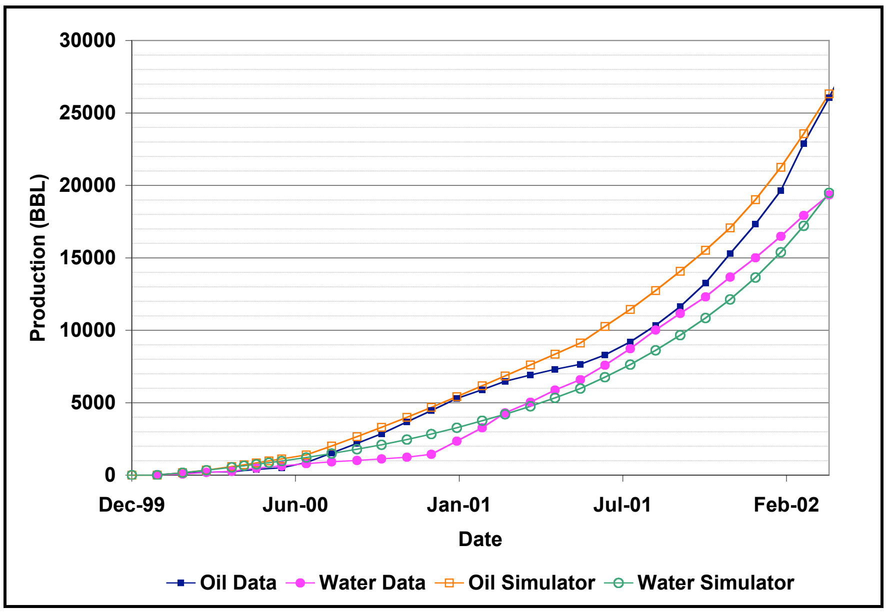

Figure 3-4. Field oil and water production vs. time. Field data vs. simulation results

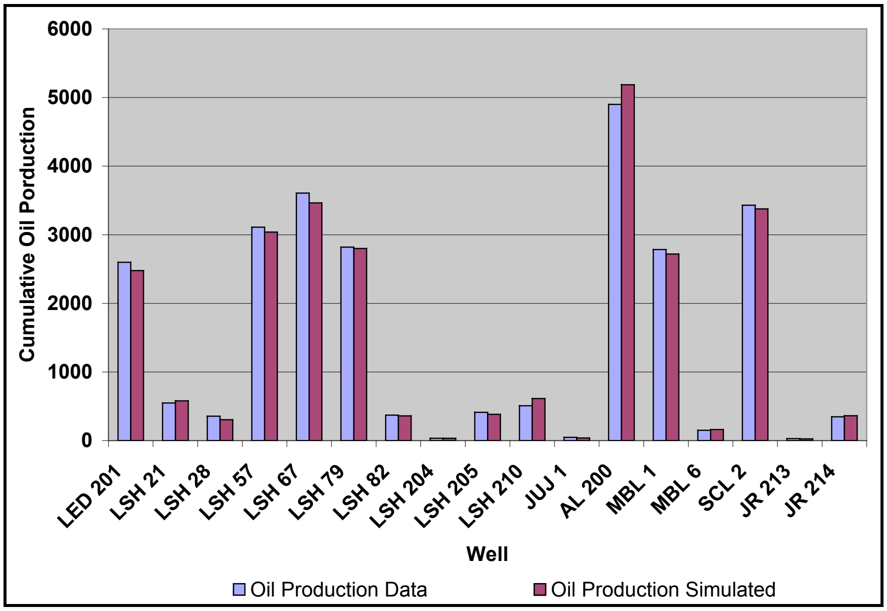

Figure 3-5. Comparison of cumulative oil production per well (February 2002)

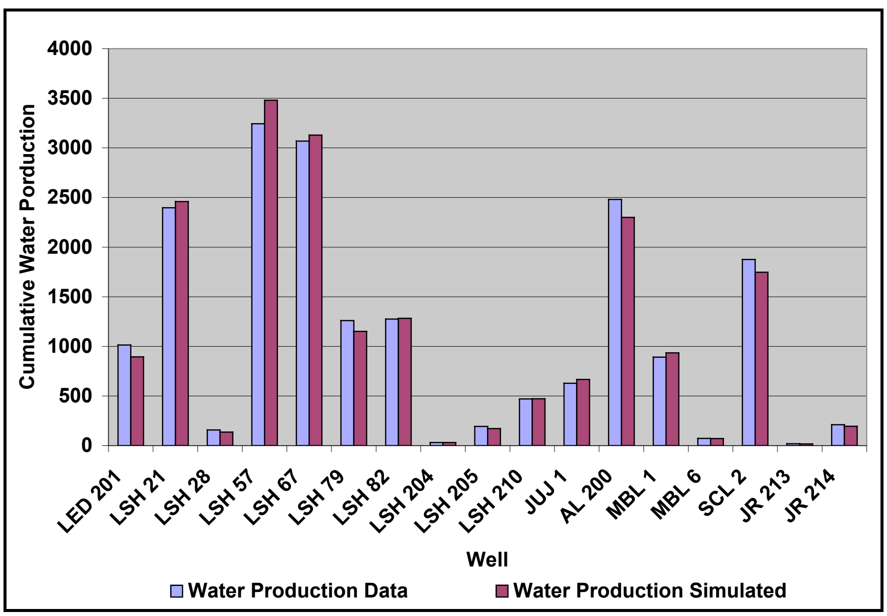

Figure 3-6. Comparison of cumulative water production per well (February 2002)

The results confirmed that the actual oil and water production of each well shows a behavior that closely approximates the simulation results. In addition, Figures 3-5 and 3-6 confirm that the simulated oil and water productions are similar to the actual productions for each well.

Figure 3-7 illustrates the deviation in the cumulative and total oil production for each well. The results show that deviation is less than 10% for 13 of the 17 wells, while the remaining wells had errors ranging from 14 to 21 %. Even though the oil production of those wells is higher than 10%, it is still acceptable since their production is small when compared with the average-well production of the field.

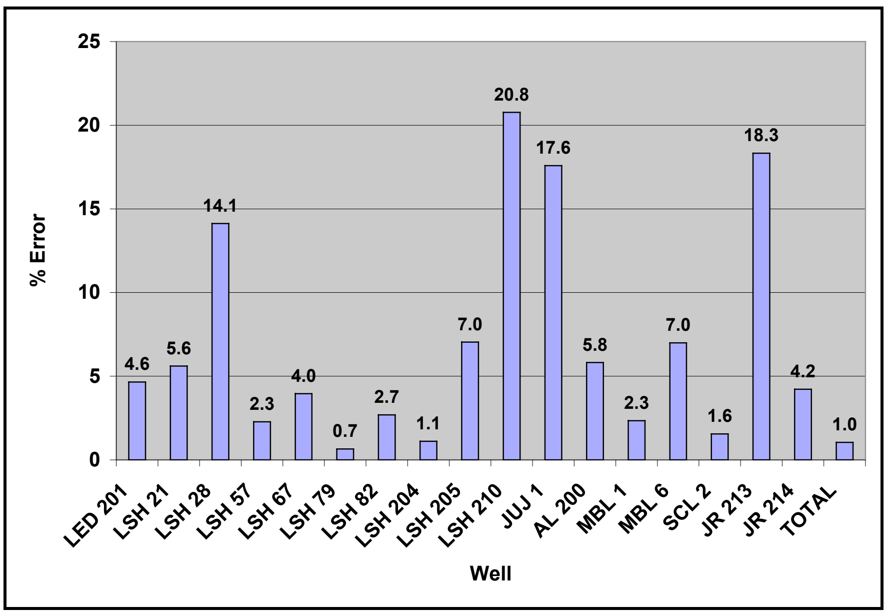

Figure 3-7. Error of the cumulative oil production per well

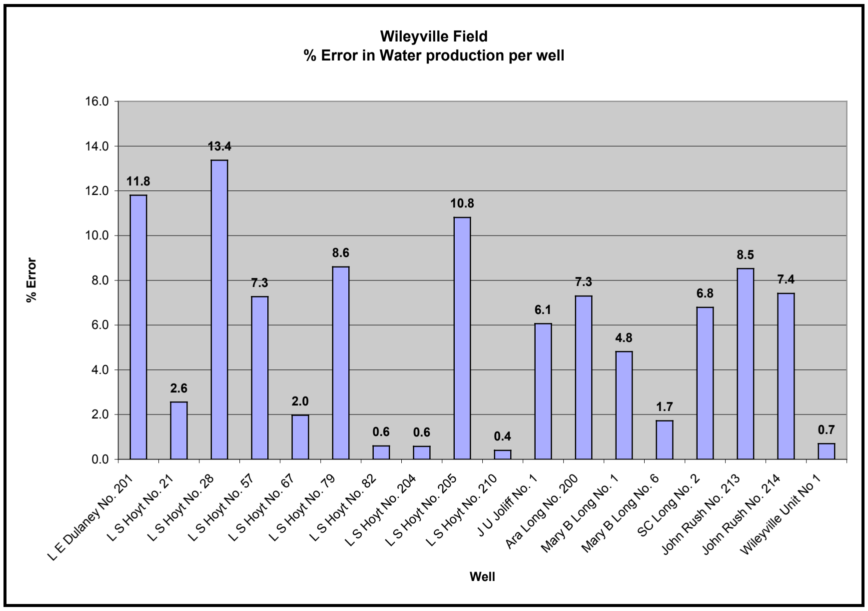

Figure 3-8. Deviation of the cumulative oil production per well

Figure 3-8 shows that the error in the water production is less than 10% for most of the wells, which makes the water production match acceptable. Figures 3-7 and 3-8 verify that the simulation represents a close approximation of the total amounts of oil and water actually produced by the field. The field scale production predicted by the simulator for each phase is within 5%. Given that the injection, pressure and production reached a satisfactory match, it can be concluded that a satisfactory history match was achieved.

3.1.4 Estimation of the unknown properties

Figure 3-9 highlights the regions where the permeability and porosity are expected to be lower than those assumed for the field (absolute permeabilities <10 md and porosities < 10%). The regions highlighted involve several wells that exhibit poor injectivity or productivity. These regions indicate that the reservoir is split into two different areas. A relatively small channel of higher permeability and porosity, as shown in Figure 3-9, apparently permits communication between the two regions of the reservoir.

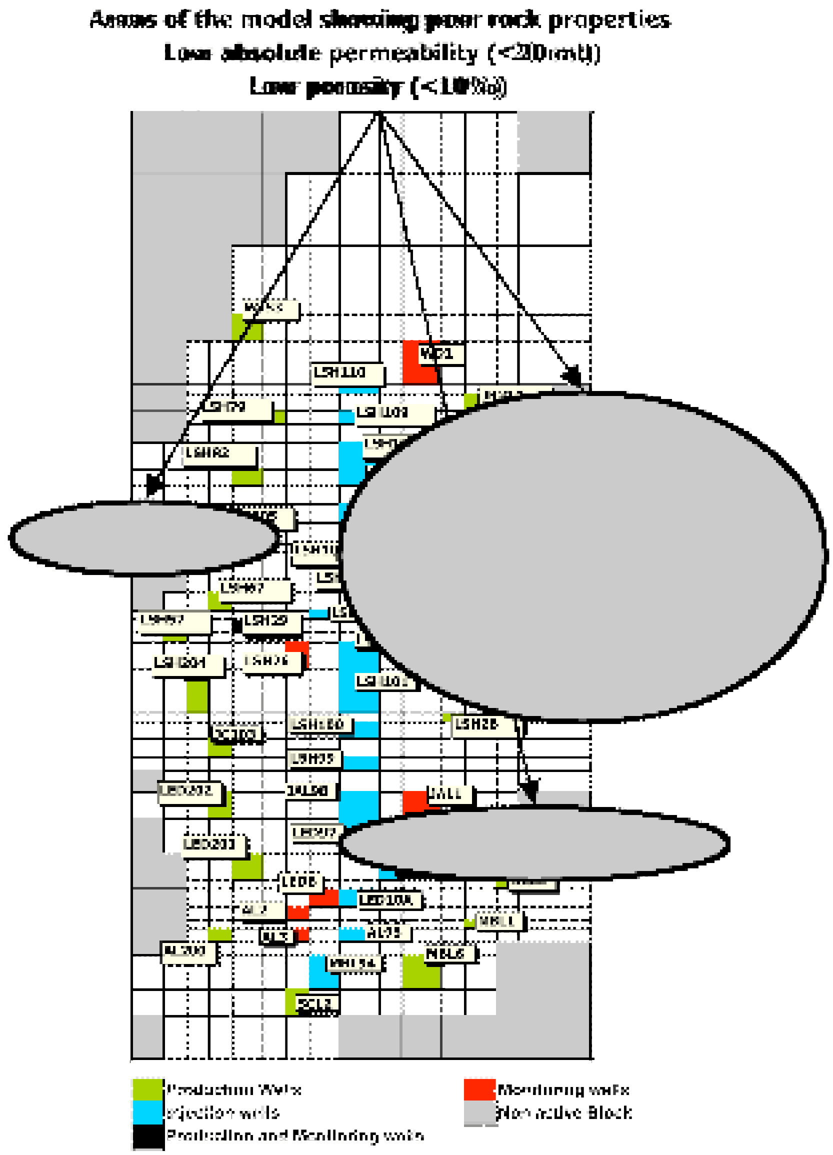

Figure 3-9. Location of the areas of low permeability and porosity in the model

Currently the most prolific wells of the waterflood are the L. S. Hoyt 67 (LSH 67) and L.S. Hoyt 57 (LSH 57) wells. These wells are located in advantageous positions. Figure 3-9 shows that the water injected from wells LSH 101, LSH 102 and LSH 103 impacts wells LSH 57 and LSH 67 and increases their pressures and oil production.

The location of these areas of low permeability and porosity help to explain the low injectivity found in wells L.S. Hoy 107 (LSH 107), L.S. Hoy 106 (LSH 106), L.S. Hoy 105 (LSH 105), L.S. Hoy 104, and L.E. Dulaney 97 (LED 97). It is recommended that additional wells be drilled and cored in these areas to verify the estimated values, and to use the information determined to update the model.

3.2 Wileyville field

For the Wileyville field, the waterflooding project for this field started in early 1997, when the injection line drive pattern was established. Almost three years after water injection began during December 1999, production was realized.

The main concern in the Wileyville field case is the distribution of properties throughout the field. The properties that affected crude oil production and the performance on the secondary recovery process are the porosity (Figure 3-10), permeability (Figure 3-11) and the thickness (Figure 3-12) of the reservoir.

The distribution of the properties on a field scale suggests that a discontinuity is present. It has been suggested that this discontinuity takes the form of a compartment. In terms of the modeling, a sudden change in rock properties was noted in the north-south direction.

Moreover, it was noted that an area of low transmissibility existed in the central portion of the field. The presence of this area will impact the development and performance of the secondary recovery operations. Moreover, this area of low permeability and porosity separates the northern and southern portions of the field.

The rock properties of the northern area are more uneven in terms of permeability and porosity when compared to those of the southern area. As a consequence, water displacement and frontal movement and production will be higher in the southern portion of the reservoir.

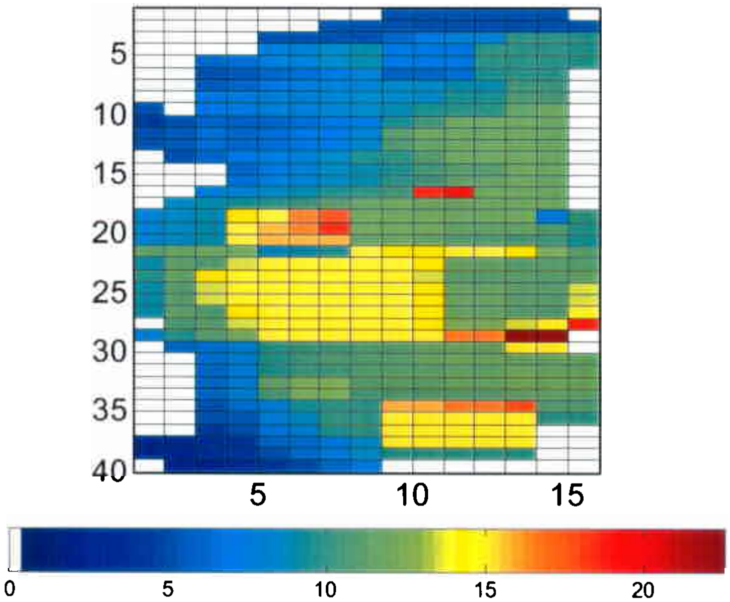

Figure 3-10 Wileyville field, thickness map.

3.2.1 Wileyville field case, injection analysis

The performance of Wileyville in terms of injectivity versus time suggests that there were injectivity problems. During the first two years of injection, the injectivity increased from approximately 100 bbl/d to 4.9 Mbbl/d. After this increase, the injectivity began to decrease reaching the current value of 2.7 Mbbl/d. All injection wells exhibited increasing skin damage during injection. The increase in skin appears to be related to the distribution of properties in this field (porosity and permeability). It also appears that historical operations played a role in the pattern developed by the skin over time.

The injection wells exhibited a trend of increasing skin damage with time after recovery from damage caused by drilling and completion operations. The initial damage lasted for about 3 months, and then an increase in the damage started. Workovers of the injection wells to reduce the damage in the near wellbore region were performed with varying degrees of success. The difference in the results of stimulation is again based on the properties present in the well. Additionally, the proximity of the wells also impacts their post stimulation performance given the fact that the reservoir properties are similar.

The injection wells of the northern portion of the field exhibit a lower injection rate when compared to those in the southern portion of the field. As previously stated, the reservoir quality of southern portion of the field is of a better quality in terms of its porosity and permeability characteristics than the northern one. Therefore, injection wells in this area possess higher injectivity rates and historically 83 % of the total water injection was realized in this area.

For the Wileyville field study, the numbers of regions containing injection wells are seven. All 18-injection wells are accounted for in these regions. Figures 3-13 to 3-19 contain the plots of skin versus time for injection wells. Figure 3-20 contains the history of wells LSH110, LSH109, LSH108 and LSH107. These wells that are located in the northern part of the field have exhibited a continuous increase in skin. This is in spite of stimulation a year into injection. In the case of wells LSH110, LSH109, LSH108 and LSH107, the location of these wells in the poorer quality reservoir rock found in the central portion of the unit is considered to be the principal reason. In the case of LSH106 (Figure 3-14), this well is located to the south separation area between the north and south portion of the field, appears to have formation qualities similar to the central part of the reservoir.

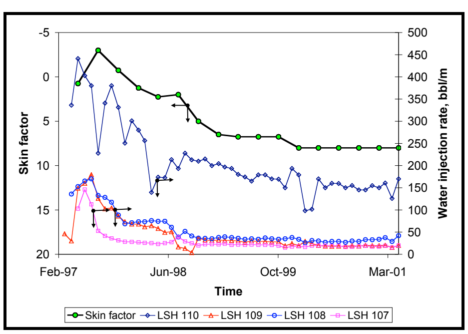

Figure 3-11: Dynamic skin in injection wells LSH110, LSH109, LSH 108 and LSH 107 of the Wileyville field.

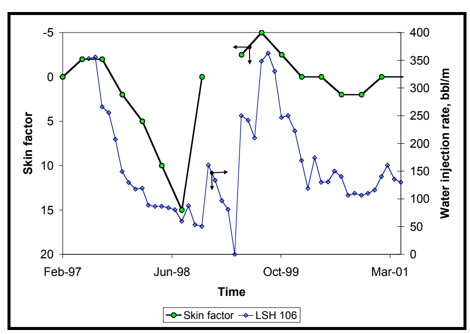

Figure 3-12: Dynamic skin in injection well LSH106 of Wileyville field.

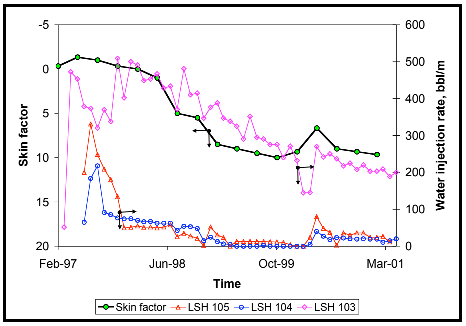

Figure 3-13: Dynamic skin in injection wells LSH105, LSH104 and LSH103 of Wileyville field.

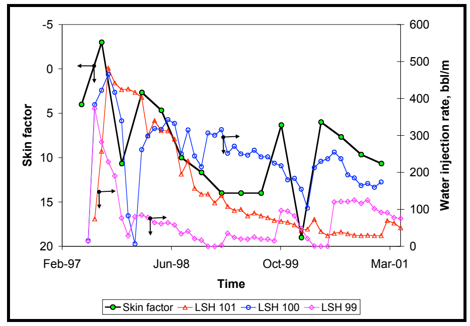

Figure 3-14: Dynamic skin in injection wells LSH101, LSH100 and LSH99 of the Wileyville field.

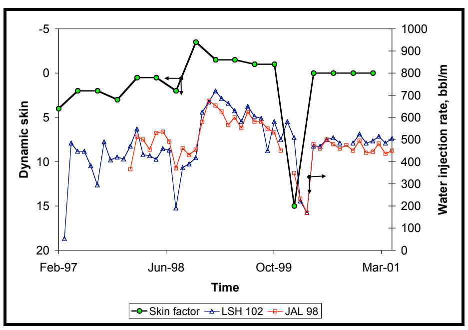

Figure 3-15: Dynamic skin in injection wells LSH102 and JAL98 of the Wileyville field.

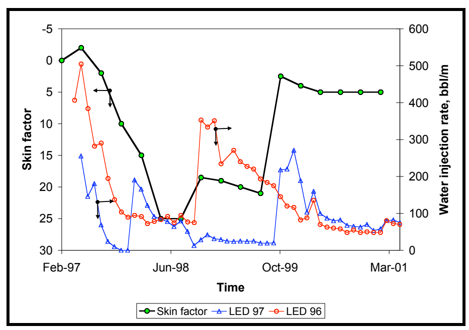

Figure 3-16: Dynamic skin in injection wells LED97 and LED96 of Wileyville field.

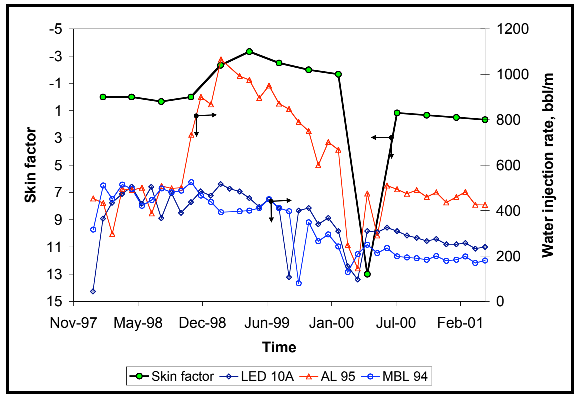

Figure 3-17: Dynamic skin in injection wells LED10A, AL95 and MBL94 of the Wileyville field.

4.0 SUMMARY

The objectives of this study were to detail efforts and techniques used to develop representative reservoir model of the Wileyville field and to provide guidelines for approaching history matching when model development is undertaken using sparse data sets. These objectives were achieved. Using sparse data sets, the reservoir model developed satisfactorily matched the behavior of the reservoir studied. This suggests that the techniques described in Chapter 2 for characterizing rock and fluid properties were appropriate.

This study shows that the rock properties could be considered uniform throughout the thickness of the reservoirs analyzed. Even though, some log analyses indicated that these reservoirs contain shales forming discontinuities and restrictions to the flow of the different phases, the results obtained suggest that the effect of these shale could be captured by varying the permeability assigned to each block in the models, and that a single layer model is a reasonable approach. These restrictions to the flow suggest that compartmentalization affects the behavior of the reservoir, and may be described in the models using permeability changes in the blocks. It can be concluded that the reservoirs studied may be appropriately described as being heterogeneous single layered.

Given the sparsely of the data, the role of the field staff proved to be crucial in determining the "acceptable" range for adjustment of the reservoir data, and for defining the "confidence" intervals for production data. In addition, the operations staff provided useful insights on the reservoirs. The field staff identified the locations of high water or gas saturations, the location of restrictions to fluid flow in the reservoirs, and reported the operating status of wells that have use for either future production or injection. The use of this data improved the "quality" of the history match by incorporating this field knowledge into the process, and thus avoided a possible numerical solution that does not represent the behavior of the fields.

This study also indicated that "apparent" skin damage varies with time and generally increases with time. The nature of the skin is dependent on matrix permeability; but also on external factors such as suspended particles and particles deposition. In the Wileyville field study, it was not possible to separate the impact of each component of skin on well performance and its change with time.

Estimates of the skin can be determined from the rate of change in the injection or production flow rates. This information can be used to optimally schedule well workovers. The results of the study suggest that the more homogeneous the reservoir rock, the greater the benefit of well stimulation reducing near wellbore damage. It is recommended to make a chemical property analysis of the emulsions that are being recovered during the workovers of the production wells. This may allow the identification of a chemical agent that could be injected into the reservoir to improve its injectivity and also reduce the time between workovers.

4.1 Wileyville field

The study suggests that waterflooding of the Wileyville field using a line-drive design was reasonable in terms of effectively displacing the oil present in the reservoir. This is particularly true in the southern portion of the reservoir where reservoir properties are remarkably uniform. The term applied to the Gordon sandstone by geologist is featureless. This implies that the sandstone is essentially homogeneous.

The study further identifies areas with low permeability and porosity. The identification of these areas supports the concept of partial compartmentalization within the reservoir. Moreover, the presence of low permeability and porosity in the central portion of the field resulted in an area of low transmissibility between the northern and southern portion of the field. Reference is made to Figure 3-9.

The quality of reservoir rock in the northern portion of the field appears to be of pure quality than the southern portion of the reservoir. To adequately develop this region of the field will require additional drilling and testing. It is possible that the injection well pattern in this portion of the field maybe need to be change to reflect the differences in rock quality between the northern and southern portion of the reservoir.

4.2 Recommendations

For study of other fields in the Appalachian basin, it is recommended that the field operations staff and the simulation team work in concert. The role of the field staff proved to be important in determining the “acceptable” range for adjustment of the reservoir data, and to define the “confidence” intervals for the production data that need to be history matched. The use of the data provided by the field staff improves the "quality" of the history match by incorporating field knowledge into the solution. This avoids a numerical solution of the problem that might not represent the behavior of the fields.

With respect to the Wileyville field, it is recommended the following strategies to improve the productivity of the reservoir be undertaken:

<u>Activation of the following as production wells</u>

W.J. Santee 4	Drill	ASAP
Jesse Shuman 206	Drill	ASAP
Jacob A. Lantz 3	Workover	ASAP
Wesley Dulaney 215	Drill	ASAP
Louise E. Dulaney 202	Workover	April 2003
L.S. Hoyt 209	Drill	September 2003
L.S. Hoyt 3	Drill	September 2004
Jennetta Chamberlain 203	Workover	January 2006
L.S. Hoyt 211	Drill	June 2006
L.S. Hoyt 208	Drill	June 2007

<u>Reconditioning of the existing production wells</u>

W.J. Santee 3	Workover	ASAP
L.S. Hoyt 204	Workover	April 2007

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